UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

☑ **Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the quarterly period ended September 30, 2006

OR

☐ **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the transition period from to

Commission file number: 000-50067

CROSSTEX ENERGY, L.P.

(Exact name of registrant as specified in its charter)

Delaware *(State of organization)*	**16-1616605** *(I.R.S. Employer Identification No.)*
2501 CEDAR SPRINGS **DALLAS, TEXAS** *(Address of principal executive offices)*	**75201** *(Zip Code)*

(214) 953-9500
(Registrant's telephone number, including area code)

Indicate by check mark whether registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☐ Accelerated filer ☑ Non-accelerated filer ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

As of November 1, 2006, the Registrant had 19,614,697 common units, 7,001,000 subordinated units, and 12,829,650 senior subordinated C units outstanding.

TABLE OF CONTENTS

CROSSTEX ENERGY, L.P.

Condensed Consolidated Balance Sheets

	September 30, 2006 (Unaudited)	December 31, 2005
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,073	$ 1,405
Accounts and notes receivable, net:		
Trade, accrued revenue, and other	325,959	442,443
Related party	113	173
Fair value of derivative assets	29,158	12,205
Natural gas and natural gas liquids in storage, prepaid expenses and other	17,357	23,549
Total current assets	373,660	479,775
Property and equipment, net of accumulated depreciation of $120,293 and $77,205, respectively	992,922	667,142
Fair value of derivatives assets	6,311	7,633
Intangible assets	644,716	255,197
Goodwill	23,074	6,568
Other assets, net	12,430	8,843
Total assets	$ 2,053,113	$ 1,425,158
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable, drafts payable and accrued gas purchases	$ 340,288	$ 437,395
Fair value of derivative liabilities	16,782	14,782
Current portion of long-term debt	10,012	6,521
Other current liabilities	40,864	32,758
Total current liabilities	407,946	491,456
Fair value of derivative liabilities	3,390	3,577
Long-term debt	891,471	516,129
Deferred tax liability	9,161	8,437
Minority interest in subsidiary	4,347	4,274
Commitments and contingencies	—	—
Partners' equity	736,798	401,285
Total liabilities and partners' equity	$ 2,053,113	$ 1,425,158

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Operations

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
	(Unaudited) (In thousands, except per unit amounts)			
Revenues:				
Midstream	$ 837,235	$ 769,334	$ 2,367,231	$ 1,928,330
Treating	17,350	13,117	47,899	34,064
Profit on energy trading activities	700	306	1,930	1,157
Total revenues	855,285	782,757	2,417,060	1,963,551
Operating costs and expenses:				
Midstream purchased gas	777,644	740,519	2,210,465	1,851,418
Treating purchased gas	2,870	2,792	7,359	5,996
Operating expenses	28,073	13,874	72,874	37,598
General and administrative	11,476	8,127	33,751	22,337
(Gain) loss on sale of property	132	(7,632)	23	(7,797)
(Gain) loss on derivatives	(3,605)	13,273	(1,839)	13,679
Depreciation and amortization	22,424	7,828	58,182	22,134
Total operating costs and expenses	839,014	778,781	2,380,815	1,945,365
Operating income	16,271	3,976	36,245	18,186
Other income (expense):				
Interest expense, net	(15,372)	(2,762)	(35,774)	(9,323)
Other	103	32	103	380
Total other income (expense)	(15,269)	(2,730)	(35,671)	(8,943)
Income before minority interest and taxes	1,002	1,246	574	9,243
Minority interest in subsidiary	(41)	(106)	(223)	(331)
Income tax provision	(58)	(68)	(356)	(176)
Net income (loss) before cumulative effect of change in accounting principle	903	1,072	(5)	8,736
Cumulative effect of change in accounting principle	—	—	689	—
Net income	$ 903	$ 1,072	$ 684	$ 8,736
General partner interest in net income	$ 4,143	$ 1,990	$ 12,181	$ 5,216
Limited partners' interest in net income (loss)	$ (3,240)	$ (918)	$ (11,497)	$ 3,520
Net income (loss) before cumulative effect of change in accounting principle per limited partners' unit:				
Basic	$ (0.12)	$ (0.05)	$ (0.47)	$ 0.19
Diluted	$ (0.12)	$ (0.05)	$ (0.47)	$ 0.18
Cumulative effect of change in accounting principle per limited partners' unit:				
Basic	—	—	$ 0.03	—
Diluted	—	—	$ 0.03	—
Net income (loss) per limited partners' unit:				
Basic	$ (0.12)	$ (0.05)	$ (0.44)	$ 0.19
Diluted	$ (0.12)	$ (0.05)	$ (0.44)	$ 0.18
Weighted average limited partners' units outstanding:				
Basic	26,602	18,157	26,245	18,126
Diluted	26,602	18,157	26,245	19,371

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Changes in Partners' Equity
Nine Months Ended September 30, 2006

(Unaudited)
(In thousands, except unit amounts)

	Common Units		Subordinated Units		Sr. Subordinated B Units		Sr. Subordinated C Units		General Partner Interest		Accumulated Other Comprehensive Income	Total
	$	Units	$	Units	$	Units	$	Units	$	Units		
Balance, December 31, 2005	$ 326,617	15,465,528	$ 16,462	9,334,000	$ 49,921	1,495,410	—	—	$ 11,522	536,631	$ (3,237)	$ 401,285
Proceeds from exercise of unit options	3,295	296,118	—	—	—	—	—	—	—	—	—	3,295
Net proceeds from issuance of senior subordinated C units	—	—	—	—	—	—	$ 359,316	12,829,650	—	—	—	359,316
Conversion of units	52,195	3,828,410	(2,274)	(2,333,000)	(49,921)	(1,495,410)	—	—	—	—	—	—
Common units for restricted units	—	19,500	—	—	—	—	—	—	—	—	—	—
Capital contributions	—	—	—	—	—	—	—	—	9,267	268,271	—	9,267
Stock-based compensation	2,176	—	777	—	—	—	—	—	2,568	—	—	5,521
Distributions	(28,937)	—	(12,252)	—	—	—	—	—	(14,769)	—	—	(55,958)
Net income (loss)	(8,302)	—	(3,195)	—	—	—	—	—	12,181	—	—	684
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	—	—	—	—	(1,110)	(1,110)
Adjustment in fair value of derivatives	—	—	—	—	—	—	—	—	—	—	14,498	14,498
Balance, September 30, 2006	$ 347,044	19,609,556	$ (482)	7,001,000	$ —	—	$ 359,316	12,829,650	$ 20,769	804,902	$ 10,151	$ 736,798

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Comprehensive Income

	Nine Months Ended September 30, 2006	2005
	(Unaudited) (In thousands)	
Net income	$ 684	$ 8,736
Hedging gains or losses reclassified to earnings	(1,110)	1,401
Adjustment in fair value of derivatives	14,498	(15,594)
Comprehensive income (loss)	$ 14,072	$ (5,457)

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Cash Flows

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
	(Unaudited) (In thousands)	
Cash flows from operating activities:		
Net income	$ 684	$ 8,736
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation and amortization	58,182	22,134
Non-cash stock-based compensation	6,210	2,273
Cumulative effect of change in accounting principle	(689)	—
(Gain) loss on sale of property	23	(7,797)
Deferred tax (benefit) expense	637	(285)
Minority interest in subsidiary	223	331
Non-cash derivatives loss	(430)	(4,848)
Amortization of debt issue costs	2,046	719
Changes in assets and liabilities, net of acquisition effects:		
Accounts receivable, accrued revenue, and other accounts receivable	127,198	(98,000)
Prepaid expenses, natural gas and natural gas liquids in storage and other	6,200	(777)
Accounts payable, accrued gas purchases, and other accrued liabilities	(124,378)	94,280
Net cash provided by operating activities	75,906	16,766
Cash flows from investing activities:		
Additions to property and equipment	(203,454)	(55,167)
Assets acquired	(569,074)	(15,969)
Proceeds from sale of property	979	9,933
Net cash used in investing activities	(771,549)	(61,203)
Cash flows from financing activities:		
Proceeds from borrowings	1,432,639	601,750
Payments on borrowings	(1,053,806)	(569,800)
Increase (decrease) in drafts payable	6,155	(10,754)
Proceeds from issuance of senior subordinated units	359,316	49,921
Capital contributions	9,267	1,528
Contributions from minority interest	—	1,287
Distribution to partners	(55,958)	(31,643)
Proceeds from exercise of unit options	3,295	846
Debt refinancing costs	(5,597)	(1,440)
Net cash provided by financing activities	695,311	41,695
Net decrease in cash and cash equivalents	(332)	(2,742)
Cash and cash equivalents, beginning of period	1,405	5,797
Cash and cash equivalents, end of period	$ 1,073	$ 3,055
Supplemental disclosures of cash flow information:		
Cash paid for interest	$ 31,854	$ 8,847
Cash paid for capital expenditure liabilities assumed in assets acquired	$ 28,841	—

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) General

Unless the context requires otherwise, references to "we","us","our" or the "Partnership" mean Crosstex Energy, L.P. and its consolidated subsidiaries.

Crosstex Energy, L.P., a Delaware limited partnership formed on July 12, 2002, is engaged in the gathering, transmission, treating, processing and marketing of natural gas and natural gas liquids. The Partnership connects the wells of natural gas producers in its market areas to its gathering systems, treats natural gas to remove impurities to ensure that it meets pipeline quality specifications, processes natural gas for the removal of natural gas liquids, or NGLs, transports natural gas and NGLs and ultimately provides natural gas to a variety of markets. The Partnership purchases natural gas from natural gas producers and other supply points and sells that natural gas to utilities, industrial customers, other marketers and pipelines and thereby generates gross margins based on the difference between the purchase and resale prices. In addition, the Partnership purchases natural gas and NGLs from producers not connected to its gathering systems for resale and sells natural gas and NGLs on behalf of producers for a fee.

Crosstex Energy GP, L.P. is the general partner of the Partnership. Crosstex Energy GP, L.P. is an indirect, wholly-owned subsidiary of Crosstex Energy, Inc. ("CEI").

The accompanying condensed consolidated financial statements are prepared in accordance with the instructions to Form 10-Q, are unaudited and do not include all the information and disclosures required by generally accepted accounting principles for complete financial statements. All adjustments that, in the opinion of management, are necessary for a fair presentation of the results of operations for the interim periods have been made and are of a recurring nature unless otherwise disclosed herein. The results of operations for such interim periods are not necessarily indicative of results of operations for a full year. All significant intercompany balances and transactions have been eliminated in consolidation. These condensed consolidated financial statements should be read in conjunction with the financial statements and notes thereto included in our annual report on Form 10-K for the year ended December 31, 2005. Certain reclassifications have been made to the consolidated financial statements for the prior year periods to conform to the current presentation.

(a) Management's Use of Estimates

The preparation of financial statements in accordance with generally accepted accounting principles in the United States of America requires management of the Partnership to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from these estimates.

(b) Revenue Recognition

The Partnership recognizes revenue for sales or services at the time the natural gas, carbon dioxide or NGLs are delivered or at the time the services are performed. The Partnership generally accrues one to two months of sales and the related gas purchases and reverses these accruals when the sales and purchases are actually invoiced and recorded in the subsequent months. Actual results could differ from the accrual estimates.

The Partnership utilizes extensive estimation procedures to determine the sales and cost of gas purchase accruals for each accounting cycle. Accruals are based on estimates of volumes flowing each month from a variety of sources. The Partnership uses actual measurement data, if it is available, and will use such data as producer/shipper nominations, prior month average daily flows, estimated flow for new production and estimated end-user requirements (all adjusted for the estimated impact of weather patterns) when actual measurement data is not available. Throughout the month or two following production, actual measured sales and transportation volumes are received and invoiced and used in a process referred to as "actualization." Through the actualization process, any estimation differences recorded through the accrual are reflected in the subsequent month's accounting cycle when the accrual is reversed and actual amounts are recorded. Actual volumes purchased, processed or sold may differ from the estimates due to a variety of factors including, but not limited to: actual wellhead production or customer requirements being higher or lower than the amount nominated at the beginning of the month; liquids recoveries being higher or lower than estimated because gas processed through the plants was richer or leaner than estimated; the estimated impact of weather patterns being different from the actual impact on sales and purchases; and pipeline maintenance or allocations causing actual deliveries of gas to be different than estimated. The Partnership believes that its accrual process for the one to two months of sales and purchases provides a reasonable estimate of such sales and purchases.

(c) Long-Term Incentive Plans

Effective January 1, 2006, the Partnership adopted the provisions of SFAS No. 123R, "*Share-Based Compensation"* ("FAS No. 123R") which requires compensation related to all stock-based awards, including stock options, be recognized in the consolidated financial statements. The Partnership applied the provisions of Accounting Principles Board Opinion No. 25, "*Accounting for Stock Issued to Employees"* ("APB No. 25"), for periods prior to January 1, 2006.

The Partnership elected to use the modified-prospective transition method. Under the modified-prospective method, awards that are granted, modified, repurchased, or canceled after the date of adoption are measured and accounted for under FAS No. 123R. The unvested portion of awards that were granted prior to the effective date are also accounted for in accordance with FAS No. 123R. The Partnership adjusted compensation cost for actual forfeitures as they occurred under APB No. 25 for periods prior to January 1, 2006. Under FAS No. 123R, the Partnership is required to estimate forfeitures in determining periodic compensation cost. The cumulative effect of the adoption of FAS No. 123R recognized on January 1, 2006 was an increase in net income of $0.7 million due to the reduction in previously recognized compensation costs associated with the estimation of forfeitures.

The Partnership and CEI each have similar unit or share-based payment plans for employees, which are described below. Share-based compensation associated with the CEI share-based compensation plans awarded to officers and employees of the Partnership are recorded by the Partnership since CEI has no operating activities other than its interest in the Partnership. Amounts recognized in the consolidated financial statements with respect to these plans are as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Cost of share-based compensation charged to general and administrative expense	$ 2,005	$ 1,048	$ 5,402	$ 2,354
Cost of share-based compensation charged to operating expense	323	95	808	304
Total amount charged to income before cumulative effect of accounting change	$ 2,328	$ 1,143	$ 6,210	$ 2,658

The Partnership has a long-term incentive plan that was adopted by the Partnership's managing general partner in 2002 for its employees, directors, and affiliates who perform services for the Partnership. The plan currently permits the grant of awards covering an aggregate of 2,600,000 common unit options and restricted units. The plan is administered by the compensation committee of the managing general partner's board of directors. The units issued upon exercise or vesting are newly issued common units.

Restricted Units

A restricted unit is a "phantom" unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit, or in the discretion of the compensation committee, cash equivalent to the value of a common unit. In addition, the restricted units will become exercisable upon a change of control of the Partnership, its general partner or its general partner's general partner.

The restricted units are intended to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, plan participants will not pay any consideration for the common units they receive and the Partnership will receive no remuneration for the units. The restricted units include a tandem award that entitles the participant to receive cash payments equal to the cash distributions made by the Partnership with respect to its outstanding common units until the restriction period is terminated or the restricted units are forfeited. The restricted units granted prior to 2005 generally vest based on five years of service (25% in years 3 and 4 and 50% in year 5) and the restricted units granted in 2005 and 2006 generally cliff vest after three years of service.

The restricted units are valued at their fair value at the date of grant which is equal to the market value of common units on such date. A summary of the restricted unit activity for the nine months ended September 30, 2006 is provided below:

	Nine Months Ended September 30, 2006	
Crosstex Energy, L.P. Restricted Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	247,648	$ 28.33
Granted	109,720	34.23
Vested	(19,500)	12.99
Forfeited	(19,608)	24.60
Non-vested, end of period	318,260	$ 31.53
Aggregate intrinsic value, end of period (in thousands)	$ 11,381	

The aggregate intrinsic value of vested units during the nine months ended September 30, 2006 was $0.7 million. As of September 30, 2006, there was $6.1 million of unrecognized compensation cost related to non-vested restricted units. That cost is expected to be recognized over a weighted-average period of 1.8 years.

Unit Options

Unit options will have an exercise price that is not less than the fair market value of the units on the date of grant. In general, unit options granted will become exercisable over a period determined by the compensation committee. In addition, unit options will become exercisable upon a change in control of the Partnership, its general partner or its general partner's general partner.

The fair value of each unit option award is estimated at the date of grant using the Black-Scholes-Merton model. This model is based on the assumptions summarized below. Expected volatilities are based on historical volatilities of the Partnership's traded common units. The Partnership has used historical data to estimate share option exercise and employee departure behavior. The expected life of unit options represents the period of time that unit options granted are expected to be outstanding. The risk-free interest rate for periods within the contractual term of the unit option is based on the U.S. Treasury yield curve in effect at the time of the grant.

Unit options are generally awarded with an exercise price equal to the market price of the Partnership's common units at the date of grant, although a substantial portion of the unit options granted during 2004 and 2005 were granted during the second quarter of each fiscal year with an exercise price equal to the market price at the beginning of the fiscal year, resulting in an exercise price that was less than the market price at grant. In accordance Accounting Principles Board Opinion No. 25, *Accounting for Stock Issue to Employees*, compensation expense was recorded during 2004 and 2005 to the extent the market value of the unit exceeded the exercise price of the unit

CROSSTEX ENERGY, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

option at the measurement date. The unit options granted prior to 2005 generally vest based on five years of service (25% in years 3 and 4 and 50% in year 5) and the unit options granted in 2005 and 2006 generally vest based on 3 years of service (one-third after each year of service). The unit options have a 10-year term.

Crosstex Energy, L.P. Unit Options Granted:	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Weighted average distribution yield	5.5%	5.5%	5.0%
Weighted average expected volatility	33.0%	33.0%	33.0%
Weighted average risk free interest rate	4.80%	4.79%	3.7%
Weighted average expected life	6 years	6 years	3 years
Weighted average contractual life	10 years	10 years	10 years
Weighted average of fair value of unit options granted	$ 7.88	$ 7.45	$ 7.93

No unit options were granted during the three months ended September 30, 2005.

A summary of the unit option activity for the nine months ended September 30, 2006 is provided below:

Crosstex Energy, L.P. Unit Options:	Nine Months Ended September 30, 2006 Number of Units	Weighted Average Exercise Price
Outstanding, beginning of period	1,039,832	$ 18.88
Granted	286,403	34.62
Exercised	(296,118)	11.22
Forfeited	(79,825)	24.76
Outstanding, end of period	950,292	$ 25.52
Options exercisable at end of period	126,865	$ 22.32
Weighted average contractual term (years) end of period:		
Options outstanding	8.1	
Options exercisable	7.7	
Aggregate intrinsic value end of period (in thousands):		
Options outstanding	$ 9,730	
Options exercisable	$ 1,705	

The total intrinsic value of unit options exercised during the nine months ended September 30, 2005 and 2006 was $2.3 million and $7.4 million, respectively. The intrinsic value of unit options exercised during the three months ended September 30, 2005 and 2006 was $0.9 million and $0.4 million, respectively. As of September 30, 2006, there was $3.0 million of unrecognized compensation cost related to non-vested unit options. That cost is expected to be recognized over a weighted-average period of 2.1 years.

CEI Long-Term Incentive Plan

CEI has one stock-based compensation plan, the Crosstex Energy, Inc. Long-Term Incentive Plan. Prior to September 6, 2006, the plan permitted the grant of awards covering an aggregate of 1,200,000 options for common stock and restricted shares. On September 6, 2006, CEI's board of directors adopted, subject to stockholder approval, an Amended and Restated Long-Term Incentive Plan that increased the number of shares of common stock authorized for issuance under the plan to 1,530,000 shares. CEI's stockholders approved the plan on

CROSSTEX ENERGY, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

October 26, 2006. The plan is administered by the compensation committee of CEI's board of directors. The shares issued upon exercise or vesting are newly issued common shares.

CEI's restricted shares are included at their fair value at the date of grant which is equal to the market value of the common stock on such date. CEI's restricted stock granted prior to 2005 generally vests based on five years of service (25% in years 3 and 4 and 50% in year 5) and restricted stock granted in 2005 and 2006 generally cliff vest after three years of service.

	Nine Months Ended September 30, 2006	
Crosstex Energy, Inc. Restricted Shares:	**Number of Shares**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	196,547	$ 43.36
Granted	54,233	72.11
Vested	—	—
Forfeited	(6,902)	48.42
Non-vested, end of period	243,878	$ 49.61
Aggregate intrinsic value, end of period (in thousands)	$ 21,844	

No CEI stock options have been granted to, or exercised or forfeited by, any officers or employees of the Partnership during the nine months ended September 30, 2006. No CEI stock options were granted to any officers or employees of the Partnership during 2005. The following is a summary of the CEI stock options outstanding attributable to officers and employees of the Partnership as of September 30, 2006:

Outstanding stock options (non exercisable)	10,000
Weighted average exercise price	$ 40.00
Aggregate intrinsic value	$ 496,000
Weighted average remaining contractual term	8.7 years

The total intrinsic value of CEI stock options exercised by officers and employees of the Partnership during the nine months ended September 30, 2005 was $27.0 million. No stock options were exercised by officers and employees of the Partnership during the three months ended September 30, 2005 or during the nine months ended September 30, 2006.

As of September 30, 2006, there was $7.1 million of unrecognized compensation costs related to non-vested CEI restricted stock and CEI's stock options. The cost is expected to be recognized over a weighted average period of 1.9 years.

CROSSTEX ENERGY, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Pro Forma for 2005:

Had compensation cost for the Partnership been determined based on the fair value at the grant date for awards in accordance with SFAS No. 123, *Accounting for Stock-based Compensation*, the Partnership's net income would have been as follows (in thousands, except per unit amounts):

	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2005
Net income, as reported	$ 1,072	$ 8,736
Add: Stock-based employee compensation expense included in reported net income	1,143	2,659
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards	(1,261)	(2,888)
Pro forma net income	$ 954	$ 8,507
Net income (loss) per limited partner unit, as reported:		
Basic	$ (0.05)	$ 0.19
Diluted	$ (0.05)	$ 0.18
Pro forma net income per limited partner unit:		
Basic	$ (0.06)	$ 0.18
Diluted	$ (0.06)	$ 0.17

(d) Earnings per Unit and Anti-Dilutive Computations

Basic earnings per unit was computed by dividing net income by the weighted average number of limited partner units outstanding for the three and nine months ended September 30, 2006 and 2005. The computation of diluted earnings per unit further assumes the dilutive effect of unit options, restricted units and senior subordinated units.

The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the three and nine months ended September 30, 2006 and 2005 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Basic earnings per unit:				
Weighted average limited partner units outstanding	26,602	18,157	26,245	18,126
Diluted earnings per unit:				
Weighted average limited partner units outstanding	26,602	18,157	26,245	18,126
Dilutive effect of restricted units issued	—	—	—	137
Dilutive effect of senior subordinated units	—	—	—	532
Dilutive effect of exercise of options outstanding	—	—	—	576
Diluted units	26,602	18,157	26,245	19,371

All outstanding units were included in the computation of diluted earnings per unit and weighted based on the number of days such units were outstanding for the period presented. All common unit equivalents were antidilutive in the three and nine months ended September 30, 2006 and the three months ended September 30, 2005 because the limited partners were allocated a net loss in the periods.

Net income is allocated to the general partner in an amount equal to its incentive distributions as described in Note (4). In June 2005, the Partnership amended its partnership agreement to allocate the expenses attributable to CEI stock options and restricted stock all to the general partner to match the related general partner contribution for such items. Therefore, beginning in the second quarter of 2005, the general partner's share of net income is reduced by stock-based compensation expense attributed to CEI stock options and restricted stock. The remaining net income after incentive distributions and CEI-related stock-based compensation is allocated pro rata between the 2% general partner interest, the subordinated units, and the common units. The net income allocated to the general partner for incentive distributions was \$5.2 million and \$2.5 million for the three months ended September 30, 2006 and 2005, respectively, and \$14.9 million and \$6.7 million for the nine months ended September 30, 2006 and 2005, respectively. Stock- based compensation related to CEI options and restricted stock was \$1.0 million and \$0.5 million for the three months ended September 30, 2006 and 2005, respectively, and \$2.5 million and \$1.6 million for the nine months ended September 30, 2006 and 2005, respectively.

(e) Income Taxes

The Partnership recorded an increase of \$0.2 million in the deferred tax liability related to the effect of tax law changes enacted by the State of Texas on May 18, 2006.

(f) New Accounting Pronouncements

In June 2006, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 48 ("FIN 48"), "*Accounting for Uncertainty in Income Taxes*". FIN 48 is an interpretation of FASB Statement No. 109, "*Accounting for Income Taxes*" and must be adopted by the Partnership no later than January 1, 2007. FIN 48 prescribes a comprehensive model for recognizing, measuring, presenting and disclosing in the financial statements uncertain tax positions taken or expected to be taken. The Partnership is a pass-thru entity and does not expect a major impact on financial statement presentation as a result of FIN 48.

(2) Significant Acquisitions

On June 29, 2006, the Partnership acquired certain natural gas gathering pipeline systems and related facilities in the Barnett Shale (the "Midstream Assets") from Chief Holdings LLC ("Chief") for a purchase price of approximately \$475.7 million (the "Chief Acquisition"). The Midstream Assets include five gathering systems, located in parts of Parker, Tarrant, Denton, Palo Pinto, Erath, Hood, Somervell, Hill and Johnson counties in Texas. The Midstream Assets also include a 125 million cubic feet per day carbon dioxide treating plant and compression facilities with 26,000 horsepower. The gas gathering systems consist of approximately 250 miles of existing gathering pipelines, ranging from four inches to twelve inches in diameter. The Partnership plans to build up to an additional 400 miles of pipelines as production in the area is drilled and developed. The gathering systems currently have the capacity to deliver approximately 250,000 MMBtu per day, and the Partnership will expand the capacity as needed to gather the volumes produced as new pipelines are constructed.

Simultaneously with the Chief Acquisition, the Partnership entered into a gas gathering agreement with Devon Energy Corporation ("Devon") whereby the Partnership has agreed to gather, and Devon has agreed to dedicate and deliver, the future production on acreage that Devon acquired from Chief (approximately 160,000 net acres). Under the agreement, Devon has committed to deliver all of the production from the dedicated acreage into the gathering system, including production from current wells and wells that it drills in the future. The Partnership will expand the gathering system to reach the new wells as they are drilled. The agreement has a 15-year term and provides for market-based gathering fees over the term. In addition to the Devon agreement, approximately 60,000 additional net acres are dedicated to the Midstream Assets under agreements with other producers.

CROSSTEX ENERGY, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The Partnership utilized the purchase method of accounting for the acquisition of the Midstream Assets with an acquisition date of June 29, 2006. The purchase price and our preliminary allocation thereof are as follows (in thousands):

Cash paid to Chief	$	475,333
Direct acquisition costs		323
Total purchase price	$	475,656
Assets acquired:		
Current assets	$	19,935
Property, plant and equipment		115,208
Intangible assets		395,391
Liabilities assumed:		
Current liabilities		(54,878)
Total purchase price	$	475,656

Intangibles relate primarily to the value of the dedicated and non-dedicated acreage attributable to the system, including the agreement with Devon, and are being amortized using the units of throughput method of amortization. The preliminary purchase price allocation has not been finalized because the Partnership is still in the process of determining the allocation of costs between tangible and intangible assets and finalizing working capital settlements.

Operating results for the Midstream Assets have been included in the Consolidated Statements of Operations since June 29, 2006. The unaudited pro forma results of operations for historical periods have not been presented herein because there are substantial differences in the way Chief operated the Midstream Assets during pre-acquisition periods and the way the Partnership operates these assets post-acquisition. Therefore, there is not sufficient continuity of operations to make the disclosure meaningful for comparative financial information.

The Partnership financed the Chief Acquisition with borrowings of approximately $105.0 million under its bank credit facility, net proceeds of approximately $368.3 million from the private placement of senior subordinated series C units, including approximately $9.0 million of equity contributions from Crosstex Energy GP, L.P., the general partner of the Partnership and an indirect subsidiary of CEI, and $6.0 million of cash.

In November 2005, the Partnership acquired El Paso Corporation's processing and natural gas liquids business in south Louisiana for $476.2 million. The assets acquired include 2.3 billion cubic feet per day of processing capacity, 66,000 barrels per day of fractionation capacity, 2.4 million barrels of underground storage and 400 miles of liquids transport lines. The Partnership financed the acquisition with net proceeds totaling $228.0 million from the issuance of common units and senior subordinated series B units (including the 2% general partner contributions totaling $4.7 million) and borrowings under its bank credit facility for the remaining balance.

CROSSTEX ENERGY, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Operating results for the El Paso assets have been included in the Consolidated Statements of Operations since November 1, 2005. The following unaudited pro forma results of operations assume that the El Paso acquisition occurred on January 1, 2005 (in thousands, except per unit amounts):

	Pro Forma Nine Months Ended September 30, 2005
Revenue	$ 2,234,379
Pro forma net income	$ 39
Pro forma net income per common unit:	
Basic	$ (0.30)
Diluted	$ (0.30)

The Partnership has utilized the purchase method of accounting for this acquisition with an acquisition date of November 1, 2005.

(3) Long-Term Debt

As of September 30, 2006 and December 31, 2005, long-term debt consisted of the following (in thousands):

	September 30, 2006	December 31, 2005
Bank credit facility, interest based on Prime and/or LIBOR plus an applicable margin, interest rates (per the facility) at September 30, 2006 and December 31, 2005 were 7.21% and 6.69%, respectively	$ 400,000	$ 322,000
Senior secured notes, weighted average interest rate at September 30, 2006 and December 31, 2005 were 6.76% and 6.64%, respectively	500,883	200,000
Note payable to Florida Gas Transmission Company	600	650
	901,483	522,650
Less current portion	(10,012)	(6,521)
Debt classified as long-term	$ 891,471	$ 516,129

On June 29, 2006, we amended our bank credit facility, increasing availability under the facility to $1 billion, with an option to increase the aggregate commitment to $1.3 billion pursuant to an accordion provision. The maturity date was extended from November 2010 to June 2011.

Under the amended credit agreement, borrowings bear interest at our option at the administrative agent’s reference rate plus 0% to 0.25% or LIBOR plus 1.00% to 1.75%. The applicable margin varies quarterly based on our leverage ratio. The fees charged for letters of credit range from 1.00% to 1.75% per annum, plus a fronting fee of 0.125% per annum. We incur quarterly commitment fees based on the unused amount of the credit facilities. The amendment to the credit facility also adjusted financial covenants requiring the Partnership to maintain:

- an initial ratio of total funded debt to consolidated earnings before interest, taxes, depreciation and amortization (each as defined in the credit agreement) measured quarterly on a rolling four-quarter basis, of 5.25 to 1.0 pro forma for any asset acquisitions. The maximum leverage ratio is reduced to 4.75 to 1.0 beginning July 1, 2007 and further reduces to 4.25 to 1.0 on January 1, 2008. The maximum leverage ratio increases to 5.25 to 1.0 during an acquisition adjustment period, as defined in the credit agreement; and
- a minimum interest coverage ratio (as defined in the credit agreement) measured quarterly on a rolling four-quarter basis, equal to 3.0 to 1.0.

In July 2006, the bank credit facility was amended to allow for borrowings under our senior secured note shelf agreement to increase from $260.0 million to $510.0 million.

In 2006, the Partnership amended the shelf agreement governing the senior secured notes to increase its availability from $200.0 million to $510.0 million. In March 2006, the Partnership issued $60.0 million aggregate principal amount of senior secured notes with an interest rate of 6.32% and a maturity of ten years. In July 2006, the Partnership issued $245.0 million aggregate principal amount of senior secured notes with an interest rate of 6.96% and a maturity of ten years.

The Partnership was in compliance with all debt covenants at September 30, 2006 and expect to be in compliance for the next twelve months.

(4) Partners' Capital

Issuance of Units

On June 29, 2006, the Partnership issued an aggregate of 12,829,650 senior subordinated series C units representing limited partner interests of the Partnership in a private equity offering for net proceeds of approximately $359.3 million. The senior subordinated series C units were issued at $28.06 per unit, which represents a discount of 25% to the market value of common units on such date. CEI purchased 6,414,830 of the senior subordinated series C units issued at that price. In addition, Crosstex Energy GP, L.P. made a general partner contribution of $9.0 million which represents a 2% general partner interest on the market value of the private equity offering.

The senior subordinated series C units will automatically convert into common units representing limited partner interests of the Partnership on the first date on or after February 16, 2008 that conversion is permitted by our partnership agreement at a ratio of one common unit for each senior subordinated series C unit. Our partnership agreement will permit the conversion of the senior subordinated series C units to common units once the subordination period ends or if the issuance is in connection with an acquisition that increases cash flow from operations per unit on a pro forma basis. If not able to convert on February 16, 2008, then the holders of such units will have the right to receive, after payment of the minimum quarterly distribution on the Partnership's common units but prior to any payment on the Partnership's subordinated units, distributions equal to 110% of the quarterly cash distribution amount payable on common units. The senior subordinated series C units are not entitled to distributions of available cash from the Partnership until February 16, 2008.

On June 24, 2005, the Partnership issued 1,495,410 senior subordinated units in a private equity offering for net proceeds of $51.1 million, including our general partners' $1.1 million capital contribution. The senior subordinated units were issued at $33.44 per unit, which represents a discount of 13.7% to the market value of common units on such date. These units automatically converted to common units on a one-for-one basis on February 24, 2006. The senior subordinated units received no distributions until their conversion to common units.

Cash Distributions

In accordance with the partnership agreement, the Partnership must make distributions of 100% of available cash, as defined in the partnership agreement, within 45 days following the end of each quarter. Distributions will generally be made 98% to the common and subordinated unitholders (other than the senior subordinated unitholders) and 2% to the general partner, subject to the payment of incentive distributions to the extent that certain target levels of cash distributions are achieved. Under the quarterly incentive distribution provisions, generally our general partner is entitled to 13% of amounts we distribute in excess of $0.25 per unit, 23% of the amounts we distribute in excess of $0.3125 per unit and 48% of amounts we distribute in excess of $0.375 per unit. Incentive distributions totaling $5.2 million and $2.5 million were earned by our general partner for the three months ended September 30, 2006 and September 30, 2005, respectively. Incentive distributions totaling $14.9 million and $6.7 million were earned in the nine-month period ending September 30, 2006 and September 30, 2005, respectively. To the extent there is sufficient available cash, the holders of common units are entitled to receive the minimum quarterly distribution of $0.25 per unit, plus arrearages, prior to any distribution of available cash to the holders of subordinated units. Subordinated units will not accrue any arrearages with respect to distributions for any quarter.

The Partnership has declared a third quarter 2006 distribution of $0.55 per unit to be paid on November 15, 2006 to unitholders of record as of November 1, 2006.

(5) Derivatives

The Partnership manages its exposure to fluctuations in commodity prices by hedging the impact of market fluctuations. Swaps are used to manage and to hedge prices and location risk related to these market exposures. Swaps are also used to manage margins on offsetting fixed-price purchase or sale commitments for physical quantities of natural gas and NGLs.

The Partnership commonly enters into various derivative financial transactions which it does not designate as hedges. These transactions include “swing swaps”, “third party on-system financial swaps”, “marketing financial swaps”, “storage swaps”, and “basis swaps”. Swing swaps are generally short-term in nature (one month), and are usually entered into to protect against changes in the volume of daily versus first-of-month index priced gas supplies or markets. Third party on-system financial swaps are hedges that the Partnership enters into on behalf of its customers who are connected to its systems, wherein the Partnership fixes a supply or market price for a period of time for its customers, and simultaneously enters into the derivative transaction. Marketing financial swaps are similar to on-system financial swaps, but are entered into for customers not connected to the Partnership’s systems. Storage swaps transactions protect against changes in the value of gas that the Partnership has stored to serve various operational requirements. Basis swaps are used to hedge basis location price risk due to buying gas into one of our systems on one index and selling gas off that same system on a different index.

In August 2005, the Partnership acquired puts, or rights to sell a portion of the liquids from the plants at a fixed price over a two-year period beginning January 1, 2006, as part of the overall risk management plan related to the acquisition of the El Paso assets. The Partnership has not designated these put options as hedges and therefore, the put options are marked to market through the Partnership’s Consolidated Statements of Operations for the three and nine months ended September 30, 2006 and 2005.

The components of (gain) loss from energy trading activities in the Consolidated Statements of Operations are (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Change in fair value of derivates that do not qualify for hedge accounting	$ (3,335)	$ 13,102	$ (336)	$ 13,734
Realized (gains) losses on derivatives	(85)	380	(1,409)	277
Ineffective portion of derivatives qualifying for hedge accounting	(185)	(209)	(94)	(332)
	$ (3,605)	$ 13,273	$ (1,839)	$ 13,679

CROSSTEX ENERGY, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The fair value of derivative assets and liabilities are as follows (in thousands):

	September 30, 2006	December 31, 2005
Fair value of derivative assets — current	$ 29,158	$ 12,205
Fair value of derivative assets — long term	6,311	7,633
Fair value of derivative liabilities — current	(16,782)	(14,782)
Fair value of derivative liabilities — long term	(3,390)	(3,577)
Net fair value of derivatives	$ 15,297	$ 1,479

Set forth below is the summarized notional amount and terms of all instruments held for price risk management purposes at September 30, 2006 (all gas quantities are expressed in British Thermal Units and liquids are expressed in gallons). The remaining term of the contracts extend no later than March 2008 for derivatives, excluding third-party on-system financial swaps, and extend to June 2010 for third-party on-system financial swaps. The Partnership's counterparties to derivative contracts include BP Corporation, Total Gas & Power, Cinergy, UBS Energy, Morgan Stanley and J. Aron & Co., a subsidiary of Goldman Sachs. Changes in the fair value of the Partnership's derivatives related to third party producers and customers' gas marketing activities are recorded in earnings in the period the transaction is entered into. The effective portion of changes in the fair value of cash flow hedges is recorded in accumulated other comprehensive income until the related anticipated future cash flow is recognized in earnings and the ineffective portion is recorded in earnings.

	September 30, 2006			
Transaction Type	Total Volume	Pricing Terms	Remaining Term of Contracts	Fair Value Assets/Liabilities (In thousands)
Cash Flow Hedges:				
Natural gas swaps	342,000	NYMEX less a basis of $0.785 to NYMEX less a basis of $0.1 or fixed prices ranging from $8.20 to $10.855 settling against various Inside FERC Index prices	October 2006 — March 2008	$ 81
Natural gas swaps	(4,458,000)		October 2006 — March 2008	7,754
Total natural gas swaps designated as cash flow hedges				$ 7,835
Liquids swaps	(34,896,662)	Fixed prices ranging from $0.6075 to $1.6275 settling against Mt. Belvieu Average of daily postings (non-TET)	October 2006 — March 2008	$ 2,370
Total liquids swaps designated as cash flow hedges				$ 2,370
Mark to Market Derivatives:				
Swing swaps	573,500	Prices ranging from Inside FERC Index to Inside FERC Index less $0.005 or fixed prices ranging from $3.95 to $3.995 settling against various Gas Daily Index prices	October 2006	$ 44
Swing swaps	(2,765,200)		October 2006	(6)
Total swing swaps				$ 38

CROSSTEX ENERGY, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	September 30, 2006			
Transaction Type	Total Volume	Pricing Terms	Remaining Term of Contracts	Fair Value Assets/Liabilities (In thousands)
Physical offset to swing swap transactions	2,765,200	Prices of various Inside FERC Index prices settling against various Gas Daily Index prices	October 2006	—
Physical offset to swing swap transactions	(573,500)		October 2006	—
Total physical offset to swing swaps				$ —
Basis swaps	28,839,700	Prices ranging from Inside FERC Index less $0.39 to Inside FERC Index plus $0.18 or fixed prices ranging from $9.52 to $10.79 settling against various Inside FERC Index prices	October 2006 — March 2008	$ (428)
Basis swaps	(28,167,000)		October 2006 — March 2008	340
Total basis swaps				$ (88)
Physical offset to basis swap transactions	8,277,000	Prices ranging from Inside FERC Index less $0.22 to Inside FERC Index plus $0.1085 settling against various Inside FERC Index prices	October 2006 — March 2007	$ (49,997)
Physical offset to basis swap transactions	(8,422,700)		October 2006 — March 2007	50,851
Total physical offset to basis swap transactions				$ 854
Third party on-system financial swaps	9,965,600	Fixed prices ranging from $4.70 to $11.91 settling against various Inside FERC Index prices	October 2006 — June 2010	$ (16,046)
Total third party on-system financial swaps				$ (16,046)
Physical offset to third party on-system transactions	(9,965,600)	Fixed prices ranging from $4.84 to $11.96 settling against various Inside FERC Index prices	October 2006 — June 2010	$ 17,038
Total physical offset to third party on-system swaps				$ 17,038
Storage swap transactions:				
Storage swap transactions	(355,000)	Fixed prices of $10.065 settling against various Inside FERC Index prices	February 2007	$ 774
Total financial storage swap transactions				$ 774
Natural gas liquid puts:				
Liquid put options (purchased)	100,787,694	Fixed prices ranging from $0.565 to $1.26 settling against Mount Belvieu Average Daily Index	October 2006 — December 2007	$ 4,799
Liquid put options (sold)	(47,181,832)		October 2006 — December 2007	(2,277)
Total natural gas liquid puts				$ 2,522

On all transactions where the Partnership is exposed to counterparty risk, the Partnership analyzes the counterparty's financial condition prior to entering into an agreement, establishes limits, and monitors the appropriateness of these limits on an ongoing basis.

Impact of Cash Flow Hedges

Natural Gas

For the nine months ended September 30, 2006, net gains on futures and basis swap hedge contracts increased gas revenue by $3.1 million. For the nine months ended September 30, 2005, net losses on futures and basis swap hedge contracts decreased gas revenue by $1.5 million. For the three months ended September 30, 2006, net gains on futures and basis swap hedge contracts increased gas revenue by $2.7 million. For the three months ended September 30, 2005, net losses on futures and basis swap hedge contracts decreased gas revenue by $1.2 million. As of September 30, 2006, an unrealized derivative fair value gain of $7.8 million related to cash flow hedges of gas price risk was recorded in accumulated other comprehensive income (loss). As of September 30, 2006, $6.4 million of the fair value gain is expected to be reclassified into earnings through September 2007. The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date, along with the realization of the gain or loss on the related physical volume, which amount is not reflected above.

The settlement of futures contracts and basis swap agreements related to October 2006 gas production increased gas revenue by approximately $1.4 million.

Liquids

For the nine months ended September 30, 2006, net gains on liquids swap hedge contracts increased liquids revenue by approximately $0.8 million. For the three months ended September 30, 2006, net losses on liquids swap hedge contracts decreased liquids revenue by $0.3 million. The Partnership had no gains or losses on liquids swap hedge contracts during the nine months ended September 30, 2005. As of September 30, 2006, an unrealized derivative fair value gain of $2.3 million related to cash flow hedges of liquids price risk was recorded in accumulated other comprehensive income (loss). As of September 30, 2006, $1.8 million of the fair value gain is expected to be reclassified into earnings through September 2007. The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date, along with the realization of the gain or loss on the related physical volume, which amount is not reflected above.

Derivatives Other than Cash Flow Hedges

Assets and liabilities related to third party derivative contracts, puts, basis swaps, swing swaps and storage swaps are included in the fair value of derivative assets and liabilities and the profit and loss on the mark-to-market value of these contracts are recorded net as gain (loss) on derivatives in the consolidated statements of operations. The Partnership estimates the fair value of all of its energy trading contracts using prices actively quoted. The estimated fair value of energy trading contracts by maturity date was as follows (in thousands):

	Maturity periods			
	Less Than One Year	One to Two Years	More Than 2 Years	Total Fair Value
September 30, 2006	$ 4,111	$ 885	$ 96	$ 5,092

(6) Transactions with Related Parties

The Partnership treats gas for, and purchases gas from, Camden Resources, Inc. (Camden) and treats gas for Erskine Energy Corporation (Erskine) and Approach Resources, Inc. (Approach). All three entities are affiliates of the Partnership by way of equity investments made by Yorktown Energy Partners IV, L.P. and Yorktown Energy Partners V, L.P., collectively a major shareholder in CEI. During the three months ended September 30, 2006 and 2005, the Partnership purchased natural gas from Camden in the amount of approximately $7.8 million and $21.1 million, respectively, and received approximately $0.6 million and $0.7 million, respectively, in treating fees from Camden. During the three months ended September 30, 2006, the Partnership received treating fees of $0.3 million and $0.1 million from Erskine and Approach, respectively. The Partnership purchased natural gas from Camden in the amount of approximately $26.5 million and $41.8 million for the nine months ended September 30, 2006 and 2005, respectively, and received approximately $2.0 million and $1.9 million, respectively, in treating fees from Camden. For the nine months ended September 30, 2006, the Partnership received treating fees of $1.0 million and $0.3 million from Erskine and Approach, respectively.

CROSSTEX ENERGY, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Purchase of Senior Subordinated Series C Units by Related Parties

On June 29, 2006, CEI purchased $180.0 million and Lubar Equity Fund, LLC purchased $8.0 million of the Partnership's senior subordinated series C units issued in a private placement. The funds raised in the private offering were used to acquire the natural gas gathering pipeline systems and related facilities of Chief Holdings LLC. Mr. Sheldon B. Lubar is a member of the board of directors of the general partner of the general partner of the Partnership and is a member of CEI's board and is also an affiliate of Lubar Equity Fund, LLC.

(7) Commitments and Contingencies

(a) Employment Agreements

Each member of executive management of the Partnership is a party to an employment contract with the general partner. The employment agreements provide each member of senior management with severance payments in certain circumstances and prohibit each such person from competing with the general partner or its affiliates for a certain period of time following the termination of such person's employment.

(b) Environmental Issues

The Partnership acquired the south Louisiana processing assets from El Paso Corporation in November 2005. One of the acquired locations, the Cow Island Gas Processing Facility, has a known active remediation project for benzene contaminated groundwater. The cause of contamination was attributed to a leaking natural gas condensate storage tank. The site investigation and active remediation being conducted at this location is under the guidance of the Louisiana Department of Environmental Quality (LDEQ) based on the Risk-Evaluation and Corrective Action Plan Program (RECAP) rules. In addition, the Partnership is working with both the LDEQ and the Louisiana State University, Louisiana Water Resources Research Institute, on the development and implementation of a new remediation technology that will drastically reduce the remediation time as well as the costs associated with such remediation projects. The estimated remediation costs are expected to be approximately $0.3 million. Since this remediation project is a result of previous owners' operation and the actual contamination occurred prior to our ownership, these costs were accrued as part of the purchase price.

In conjunction with the acquisition of the Hanover assets in January 2006, the Partnership and Hanover Compressor Company on January 11, 2006 jointly filed a "Notice of Intent" for coverage under the Texas Environmental, Health and Safety Audit Privilege Act ("Audit Act") pending the asset sale transaction. Coverage under the Audit Act allows for an environmental compliance audit of the facility operations, applicable laws, regulations and permits to be conducted. Pursuant to Section 19(g) of the Audit Act, immunity for certain violations that are voluntarily disclosed as a result of a compliance audit is granted. Pursuant to Section 4(e) of the Audit Act, the audit will be completed within six months of the date of its commencement.

(c) Other

The Partnership is involved in various litigation and administrative proceedings arising in the normal course of business. In the opinion of management, any liabilities that may result from these claims would not individually or in the aggregate have a material adverse effect on its financial position or results of operations.

(8) Segment Information

Identification of operating segments is based principally upon differences in the types and distribution channel of products. The Partnership's reportable segments consist of Midstream and Treating. The Midstream division consists of the Partnership's natural gas gathering and transmission operations and includes the Mississippi System, the Conroe System, the Gulf Coast System, the Corpus Christi System, the Gregory Gathering System located around the Corpus Christi area, the Arkoma system in Oklahoma, the Vanderbilt System located in south Texas, the LIG pipelines and processing plants located in Louisiana, the south Louisiana processing and liquids assets, the

North Texas Pipeline from the Barnett Shale, Barnett Shale gathering and processing and various other small systems. Also included in the Midstream division are the Partnership's energy trading operations. The operations in the Midstream segment are similar in the nature of the products and services, the nature of the production processes, the type of customer, the methods used for distribution of products and services and the nature of the regulatory environment. The Treating division generates fees from its plants either through volume-based treating contracts or though fixed monthly payments. Also included in the Treating division are four gathering systems that are connected to the treating plants and the Seminole plant located in Gaines County, Texas.

The Partnership evaluates the performance of its operating segments based on earnings before income taxes, interest of non-controlling partners in the Partnership's net income and accounting changes, and after an allocation of corporate expenses. Corporate expenses and stock-based compensation are allocated to the segments on a pro rata basis based on the number of employees within the segments. Interest expense is allocated on a pro rata basis based on segment assets. Inter-segment sales are at cost.

CROSSTEX ENERGY, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Summarized financial information concerning the Partnership's reportable segments is shown in the following table. The information includes all significant non-cash items.

	Midstream	Treating	Totals
		(In thousands)	
Three months ended September 30, 2006:			
Sales to external customers	$ 837,235	$ 17,350	$ 854,585
Inter-segment sales	3,201	(3,201)	—
Interest expense, net	13,690	1,682	15,372
Depreciation and amortization	18,032	4,392	22,424
Segment profit	(234)	1,236	1,002
Segment assets	1,850,752	202,361	2,053,113
Capital expenditures*	94,657	13,595	108,252
Three months ended September 30, 2005:			
Sales to external customers	$ 769,334	$ 13,117	$ 782,451
Inter-segment sales	2,384	(2,384)	—
Interest expense, net	2,232	530	2,762
Depreciation and amortization	5,094	2,734	7,828
Segment profit	(906)	2,152	1,246
Segment assets	631,960	122,831	754,791
Capital expenditures*	25,526	3,861	29,387
Nine months ended September 30, 2006:			
Sales to external customers	$ 2,367,231	$ 47,899	$ 2,415,130
Inter-segment sales	8,151	(8,151)	—
Interest expense, net	31,937	3,837	35,774
Depreciation and amortization	46,950	11,232	58,182
Segment profit	(5,096)	5,670	574
Segment assets	1,850,752	202,361	2,053,113
Capital expenditures*	180,272	25,946	206,218
Nine months ended September 30, 2005:			
Sales to external customers	$ 1,928,330	$ 34,064	$ 1,962,394
Inter-segment sales	6,287	(6,287)	—
Interest expense, net	7,458	1,865	9,323
Depreciation and amortization	14,438	7,696	22,134
Segment profit	4,887	4,356	9,243
Segment assets	631,960	122,831	754,791
Capital expenditures*	38,540	16,627	55,167

* Excluding acquisitions

(9) Subsequent Event

On October 3, 2006 the Partnership announced that it has purchased the amine-treating business of Cardinal Gas Solutions Limited Partnership for $6.4 million. The acquisition adds 12 dew point control plants and eight amine-treating plants to Crosstex's plant portfolio.

Item 2. ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

You should read the following discussion of our financial condition and results of operations in conjunction with the financial statements and notes thereto included elsewhere in this report.

Overview

We are a Delaware limited partnership formed by Crosstex Energy, Inc. ("CEI") on July 12, 2002 to indirectly acquire substantially all of the assets, liabilities and operations of our predecessor, Crosstex Energy Services, Ltd. We have two industry segments, Midstream and Treating, with a geographic focus along the Texas Gulf Coast, the North Texas Barnett Shale area, Louisiana and Mississippi. Our Midstream division focuses on the gathering, processing, transmission and marketing of natural gas and natural gas liquids, or NGLs, as well as providing certain producer services, while our Treating division focuses on the removal of contaminants from natural gas and NGLs to meet pipeline quality specifications. For the nine months ended September 30, 2006, 81% of our gross margin was generated in the Midstream division with the balance in the Treating division. We manage our business by focusing on gross margin because our business is generally to purchase and resell gas for a margin, or to gather, process, transport, market or treat gas and NGLs for a fee. We buy and sell most of our gas at a fixed relationship to the relevant index price, and hedge a significant portion of the gas that is bought based on a percentage of the relevant index in order to protect our margins from changes in gas prices. In addition, we receive certain fees for processing based on a percentage of the liquids produced and enter into hedge contracts for our expected share of the liquids to protect our margins from changes in liquids prices. As explained under "Commodity Price Risk" below, we enter into financial instruments to reduce volatility in our gross margin due to price fluctuations.

Since the formation of our predecessor, we have grown significantly as a result of our construction and acquisition of gathering and transmission pipelines and treating and processing plants. From January 1, 2000 through September 30, 2006, we have invested over $1.7 billion to develop or acquire new assets. The purchased assets were acquired from numerous sellers at different periods and were accounted for under the purchase method of accounting. Accordingly, the results of operations for such acquisitions are included in our financial statements only from the applicable date of the acquisition. As a consequence, the historical results of operations for the periods presented may not be comparable.

Our Midstream segment margins are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through our pipeline systems or processed at our processing facilities, and the volumes of NGLs handled at our fractionation facilities. Our Treating segment margins are largely a function of the number and size of treating plants in operation and fees earned for removing impurities from NGLs at a non-operated processing plant. We generate revenues from five primary sources:

- purchasing and reselling or transporting natural gas on the pipeline systems we own;
- processing natural gas at our processing plants and fractionating and marketing the recovered NGLs;
- treating natural gas at our treating plants;
- recovering carbon dioxide and NGLs at a non-operated processing plant; and
- providing off-system marketing services for producers.

The bulk of our operating profits has historically been derived from the margins we realize for gathering and transporting natural gas through our pipeline systems. Generally, we buy gas from a producer, plant or transporter at either a fixed discount to a market index or a percentage of the market index. We then transport and resell the gas. The resale price is based on the same index price at which the gas was purchased, and, if we are to be profitable, at a smaller discount or larger premium to the index than it was purchased. We attempt to execute all purchases and sales substantially concurrently, or we enter into a future delivery obligation, thereby establishing the basis for the margin we will receive for each natural gas transaction. Our gathering and transportation margins related to a percentage of the index price can be adversely affected by declines in the price of natural gas. See "Commodity Price Risk" below for a discussion of how we manage our business to reduce the impact of price volatility.

Processing and fractionation revenues are largely fee based. Our processing fees are usually based on either a percentage of the liquids volume recovered or a fixed fee per unit processed. Fractionation and marketing fees are generally fixed fee per unit of products.

We generate treating revenues under three arrangements:

- a fixed fee for operating the plant for a certain period, which accounted for approximately 51% and 37% of the operating income in our Treating division for the nine months ended September 30, 2006 and 2005, respectively;
- a volumetric fee based on the amount of gas treated, which accounted for approximately 31% and 53% of the operating income in our Treating division for the nine months ended September 30, 2006 and 2005, respectively; or
- a fee arrangement in which the producer operates the plant, which accounted for approximately 18% and 10% of the operating income in our Treating division for the nine months ended September 30, 2006 and 2005, respectively.

Operating expenses are costs directly associated with the operations of a particular asset. Among the most significant of these costs are those associated with direct labor and supervision and associated transportation and communication costs, property insurance, ad valorem taxes, repair and maintenance expenses, measurement and utilities. These costs are normally fairly stable across broad volume ranges, and therefore do not normally decrease or increase significantly in the short term with decreases or increases in the volume of gas moved through the facility.

We have grown significantly through asset purchases in recent years. These acquisitions create many of the major differences when comparing operating results from one period to another. The most significant asset purchases since January 2005 were the acquisition of the Chief Holdings LLC (“Chief”) natural gas pipeline systems and related facilities in the Barnett Shale in June 2006, the acquisition of Hanover Compression Company treating assets in February 2006, the acquisition of El Paso Corporation’s processing and liquids business in south Louisiana in November 2005, the acquisition of Graco Operations’ treating assets in January 2005 and the acquisition of Cardinal Gas Services’ treating and dewpoint control assets in May 2005.

On June 29, 2006, we acquired the natural gas gathering pipeline systems and related facilities of Chief in the Barnett Shale for $475.7 million. The acquired systems consist of approximately 250 miles of existing pipeline with up to an additional 400 miles of planned pipelines, located in Parker, Tarrant, Denton, Palo Pinto, Erath, Hood, Somervell, Hill and Johnson counties, all of which are located in Texas. The acquired assets also include a 125 million cubic feet per day carbon dioxide treating plant and compression facilities with 26,000 horsepower. At closing, approximately 160,000 net acres previously owned by Chief and acquired by Devon Energy Corporation simultaneously with our acquisition, as well as 60,000 net acres owned by other producers, were dedicated to the systems.

On February 1, 2006, we acquired 48 amine treating plants from a subsidiary of Hanover Compression Company for $51.6 million. After this acquisition we have approximately 160 treating plants in operation and a total fleet of approximately 190 units.

On November 1, 2005, we acquired El Paso Corporation’s (“El Paso”) processing and liquids business in south Louisiana for $476.2 million. The assets acquired include 2.3 billion cubic feet per day of processing capacity, 66,000 barrels per day of fractionation capacity, 2.4 million barrels of underground storage and 400 miles of liquids transport lines. The primary facilities and other assets we acquired consist of: (1) the Eunice processing plant and fractionation facility; (2) the Pelican processing plant; (3) the Sabine Pass processing plant; (4) a 23.85% interest in the Blue Water gas processing plant; (5) the Riverside fractionator and loading facility; (6) the Cajun Sibon pipeline; and (7) the Napoleonville natural gas liquid storage facility. In 2006, we acquired an additional 35.42% interest in the Blue Water gas processing plant for $16.4 million and became the operator of the plant.

On January 2, 2005, we acquired all of the assets of Graco Operations for $9.26 million. Graco’s assets consisted of 26 treating plants and associated inventory. On May 1, 2005, we acquired all of the assets of

Cardinal Gas Services for $6.7 million. Cardinal's assets consisted of nine gas treating plants, 19 operating wellhead gas processing plants for dewpoint suppression and equipment inventory.

Subsequent Events

On October 3, 2006, the Partnership announced that it has purchased the amine-treating business of Cardinal Gas Solutions Limited Partnership for $6.4 million. The acquisition adds 12 dew point control plants and eight amine-treating plants to Crosstex's plant portfolio. After this acquisition the Partnership owns 168 amine-treating plants and 37 dew point control plants in service.

Results of Operations

Set forth in the table below is certain financial and operating data for the Midstream and Treating divisions for the periods indicated.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(Dollars in millions)			
Midstream revenues	$ 837.2	$ 769.3	$ 2,367.2	$ 1,928.3
Midstream purchased gas	777.6	740.5	2,210.5	1,851.4
Profit on energy trading activities	0.7	0.3	1.9	1.2
Midstream gross margin	60.3	29.1	158.6	78.1
Treating revenues	17.4	13.1	47.9	34.1
Treating purchased gas	2.9	2.8	7.4	6.0
Treating gross margin	14.5	10.3	40.5	28.1
Total gross margin	$ 74.8	$ 39.4	$ 199.1	$ 106.2
Midstream Volumes (MMBtu/d):				
Gathering and transportation	1,487,000	1,186,000	1,422,000	1,196,000
Processing	2,060,000	452,000	1,934,000	450,000
Producer services	95,000	188,000	152,000	186,000
Plants in service at end of period	154	111	154	111

Three Months Ended September 30, 2006 Compared to Three Months Ended September 30, 2005

Gross Margin and Profit on Energy Trading Activities. Midstream gross margin was $60.3 million for the three months ended September 30, 2006 compared to $29.1 million for the three months ended September 30, 2005, an increase of $31.2 million, or 107%. This increase was primarily due to acquisitions, increased system throughput and a favorable processing environment for NGLs.

The south Louisiana natural gas processing and liquids business acquired from El Paso in November 2005 contributed $17.2 million to Midstream gross margin in the third quarter of 2006. This amount was driven by the three largest processing plants, Eunice, Sabine Pass and Pelican, which contributed gross margin amounts of $7.9 million, $2.8 million and $2.2 million, respectively. The Riverside fractionation facility also contributed $2.1 million in gross margin to the south Louisiana operations. Crosstex acquired the North Texas gathering system from Chief in June 2006. These assets and related facilities contributed $5.1 million of gross margin during the quarter. The North Texas Pipeline ("NTPL") commenced operation during the second quarter of 2006 and contributed $2.3 million in gross margin. Operational improvements and volume increases on the LIG system contributed margin growth of $3.4 million. Increased processing volumes at the Gibson and Plaquemine plants, due to recent drilling successes by producers and increased unit margins due to favorable NGLs markets accounted for a $2.7 million increase in gross margin.

Treating gross margin was $14.5 million for the three months ended September 30, 2006 compared to $10.3 million in the same period in 2005, an increase of $4.2 million, or 40%. Treating plants in service increased from 111 plants at September 2005 to 154 plants at June 2006. The increase is primarily due to the acquisition of the amine treating assets from Hanover Compressor Company in February of 2006. New plants associated with the Hanover acquisition contributed $2.1 million in gross margin growth. Plant additions from inventory contributed an additional $2.1 million in gross margin. The acquisition and installation of dew point control plants contributed an additional $0.2 million to gross margin.

Operating Expenses. Operating expenses were $28.1 million for the three months ended September 30, 2006 compared to $13.9 million for the three months ended September 30, 2005, an increase of $14.2 million, or 102%. Midstream operating expenses increased by $8.7 million due to the acquisition of the south Louisiana assets from El Paso. Other Midstream increases of $3.5 million resulted largely from the commencement of operations of the NTPL as well as the acquisition of the Chief midstream assets. The growth in treating plants in service over the two time periods increased operating expenses by $1.8 million.

General and Administrative Expenses. General and administrative expenses were $11.5 million for the three months ended September 30, 2006 compared to $8.1 million for the three months ended September 30, 2005, an increase of $3.4 million, or 41.9%. A substantial part of the increased expenses resulted primarily from staffing related costs of $1.2 million. The staff additions associated with the requirements of the El Paso, Hanover and Chief acquisitions accounted for the majority of the $1.2 million increase. Audit and other professional fees, office rent, supplies, utilities and other administrative expenses, which increased due to our growth, accounted for $1.2 million of the increase. General and administrative expenses included stock-based compensation expense of $2.0 million and $1.0 million for the three months ended September 30, 2006 and 2005, respectively. The $1.0 million increase in stock-based compensation, determined in accordance with FAS 123R during 2006 and in accordance with APB25 in 2005, primarily relates to an increase in restricted stock and unit grants due to an increase in the pool of eligible participants.

Gain/Loss on Derivatives. We had a gain on derivatives of $3.6 million for the three months ended September 30, 2006 compared to a loss of $13.2 million for the three months ended September 30, 2005. The gain in 2006 includes a gain of $1.1 million on puts acquired in 2005 related to the acquisition of the El Paso assets, a gain of $1.1 million associated with our basis swaps, a gain of $0.2 million due to ineffectiveness in our hedged derivatives, a gain of $0.9 million on storage financial transactions, and a gain of $0.3 million associated with derivatives for third-party on-system financial transactions (including $0.2 million of realized gains). As of September 30, 2006, the fair value of the puts was $2.5 million. The loss in 2005 includes a $11.5 million loss on the puts related to the acquisition of the El Paso assets.

Gain/Loss on Sale of Property. Assets sold during the three months ended September 30, 2006 generated a loss of less than $0.2 million. A gain of $8.0 million on the sale of an idle processing plant was recognized in the three months ended September 30, 2005. The gain in 2005 was partially offset by a $0.4 million net loss on other small assets sold.

Depreciation and Amortization. Depreciation and amortization expenses were $22.4 million for the three months ended September 30, 2006 compared to $7.8 million for the three months ended September 30, 2005, an increase of $14.6 million, or 186.5%. Midstream depreciation and amortization increased $8.4 million due to the acquisition of the south Louisiana assets and intangibles, $2.5 million due to the Chief assets acquired in June 2006 and $1.5 million to NTPL which was placed in service April 2006. New treating plants placed in service and assets acquired from Hanover resulted in an increase of $1.6 million of depreciation and amortization expenses. The remaining $0.7 million increase in depreciation and amortization expenses is a result of expansion projects, including our office expansions and other new assets.

Interest Expense. Interest expense was $15.4 million for the three months ended September 30, 2006 compared to $2.8 million for the three months ended September 30, 2005, an increase of $12.6 million. The increase relates primarily to an increase in debt outstanding as a result of acquisitions and other growth projects and higher interest rates between three-month periods (weighted average rate of 7.0% in 2006 compared to 6.4% in 2005).

Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005

Gross Margin and Profit on Energy Trading Activities. Midstream gross margin was $158.6 million for the nine months ended September 30, 2006 compared to $78.1 million for the nine months ended September 30, 2005, an increase of $80.6 million, or 103%. This increase was primarily due to acquisitions, increased system throughput and a favorable processing environment for NGLs.

The south Louisiana natural gas processing and liquids business acquired from El Paso in November 2005 contributed $55.4 million to Midstream gross margin for the period. This amount was driven by the three largest processing plants, Eunice, Pelican, and Sabine Pass, which contributed gross margin amounts of $25.0 million, $10.7 million and $9.3 million, respectively. The Riverside fractionation facility also contributed $5.3 million in gross margin to the south Louisiana operations. Increased processing volumes at the Gibson and Plaquemine plants, due to recent drilling successes by producers, and increased unit margins due to favorable NGLs markets accounted for a $7.2 million increase in gross margin. Crosstex acquired the North Texas gathering system from Chief in June 2006. These assets and related facilities contributed $5.7 million of gross margin growth. Operational improvements and volume increases on the Mississippi system and Crosstex Pipeline contributed margin growth of $5.4 million and $1.5 million, respectively. The NTPL commenced operation during the second quarter of 2006 and contributed $4.3 million in gross margin for the period.

Treating gross margin was $40.5 million for the nine months ended September 30, 2006 compared to $28.1 million in the same period in 2005, an increase of $12.4 million, or 44%. Treating plants in service increased from 111 plants at September 2005 to 154 plants at September 2006. The increase is primarily due to the acquisition of the amine treating assets from Hanover Compressor Company in February of 2006. New plants associated with the Hanover acquisition contributed $5.2 million in gross margin growth. Plant additions from inventory contributed an additional $4.0 million in gross margin. Existing plant assets contributed $2.4 million in gross margin growth primarily due to plant expansion projects and increased volumes. The acquisition and installation of dew point control plants contributed an additional $0.4 million to gross margin.

Operating Expenses. Operating expenses were $72.9 million for the nine months ended September 30, 2006 compared to $37.6 million for the nine months ended September 30, 2005, an increase of $35.3 million, or 93.9%. An increase of $24.2 million in operating expenses was associated with the acquisition of the south Louisiana assets. Other Midstream increases of $4.1 million were due to the commencement of operations of the NTPL as well as the Chief acquisition. The growth in the number of treating plants in service increased operating expenses by $4.9 million. Operating expenses increased $0.5 million due to stock-based compensation expenses of $0.8 million and $0.3 million for the nine months ended September 30, 2006 and 2005, respectively.

General and Administrative Expenses. General and administrative expenses were $33.8 million for the nine months ended September 30, 2006 compared to $22.3 million for the nine months ended September 30, 2005, an increase of $11.4 million, or 51.1%. A substantial part of the increased expenses resulted primarily from staffing related costs of $6.3 million. The staff additions associated with the requirements of the El Paso, Hanover and Chief acquisitions accounted for the majority of the $6.3 million increase. Audit, legal and other consulting fees, office rent, travel, training and other administrative expenses, which increased due to our growth, accounted for $2.1 million of the increase. General and administrative expenses included stock-based compensation expense of $5.4 million and $2.4 million for the nine months ended September 30, 2006 and 2005, respectively. The $3.0 million increase in stock-based compensation, determined in accordance with FAS 123R during 2006 and in accordance with APB25 in 2005, primarily relates to an increase in restricted stock and unit grants due to an increase in the pool of eligible participants.

Gain/Loss on Derivatives. We had a gain on derivatives of $1.8 million for the nine months ended September 30, 2006 compared to a loss of $13.7 million for the nine months ended September 30, 2005. The gain in 2006 includes a gain of $2.3 million on storage financial transactions (including $0.7 million of realized gain), a gain of $0.7 million associated with our basis swaps, a gain of $1.4 million associated with derivatives for third-party on-system financial transactions (including $0.8 million of realized gains), and a gain of $0.1 million due to ineffectiveness in our hedged derivatives partially offset by a loss of $2.7 million on puts acquired in 2005 related to the acquisition of the El Paso assets. As of September 30, 2006, the fair value of the puts was $2.5 million. The loss in 2005 includes a $11.5 million loss on the puts related to the acquisition of the El Paso assets.

Gain/Loss on Sale of Property. Assets sold during the nine months ended September 30, 2006 generated a net loss of less than $0.1 million as compared to a gain of $8.0 million on the sale of an idle processing plant recognized during the nine months ended September 30, 2005. The gain recognized in 2005 was partially offset by a $0.2 million net loss on other assets sold.

Depreciation and Amortization. Depreciation and amortization expenses were $58.2 million for the nine months ended September 30, 2006 compared to $22.1 million for the nine months ended September 30, 2005, an increase of $36.1 million, or 162.9%. Midstream depreciation and amortization increased $24.8 million due to the acquisition of the south Louisiana assets and intangibles, $2.5 million due to Chief assets acquired in June 2006 and $2.4 million due to the NTPL which was placed in service April 2006. The new plants acquired from Hanover, together with new treating plants placed in service, resulted in an increase of $4.4 million. The remaining $2.0 million increase in depreciation and amortization expenses is a result of expansion projects, including our office expansions and other new assets.

Interest Expense. Interest expense was $35.8 million for the nine months ended September 30, 2006 compared to $9.3 million for the nine months ended September 30, 2005, an increase of $26.5 million. The increase relates primarily to an increase in debt outstanding as a result of acquisitions and other growth projects and higher interest rates between nine-month periods (weighted average rate of 6.8% in 2006 compared to 6.3% in 2005).

Critical Accounting Policies

Information regarding the Partnership's Critical Accounting Policies is included in Item 7 of the Partnership's Annual Report on Form 10-K for the year ended December 31, 2005.

Liquidity and Capital Resources

Cash Flows. Net cash provided by operating activities was $75.9 million for the nine months ended September 30, 2006 compared to $16.8 million for the nine months ended September 30, 2005. Income before non-cash income and expenses increased by $45.6 million from $21.3 million in 2005 to $66.9 million in 2006. Changes in working capital used $9.0 million in cash flows from operating activities in 2006 as compared to $4.5 million in cash flows used by working capital changes in 2005. Our working capital deficit has increased in 2006 as discussed under "Working Capital Deficit" below.

Net cash used in investing activities was $771.5 million and $61.2 million for the nine months ended September 30, 2006 and 2005, respectively. Net cash used in investing activities during 2006 related to the $504.5 million Chief acquisition ($475.3 million paid to Chief, $0.3 million of direct acquisition costs and $28.9 million for assumed capital expenditure liabilities paid by us after acquisition), the $51.6 million Hanover acquisition and a $16.4 million acquisition of our additional interest in the Blue Water processing plant. Costs for the nine months ended September 30, 2006 associated with the connection of new wells to various systems, pipeline integrity projects, pipeline relocations and various other internal growth projects totaled $203.5 million, including costs related to the construction of the NTPL of $44.6 million, construction of the Parker County gathering project of $46.2 million, the construction of the north Louisiana pipeline expansion of $20.8 million and the expansion of the North Texas Gathering System acquired from Chief of $10.3 million.

Net cash provided by financing activities was $695.3 million for the nine months ended September 30, 2006 compared to $41.7 million provided by financing activities for the nine months ended September 30, 2005. Net cash provided by financing activities for the nine months ended September 30, 2006 included $368.3 million from the issuance of senior subordinated series C units, including the general partner contribution, net bank borrowings of $78.0 million and net borrowings under our senior secured notes of $300.9 million. Distributions to partners totaled $56.0 million in the nine months ended September 30, 2006, compared to distributions in the nine months ended September 30, 2005 of $31.6 million. Drafts payable decreased by $10.8 million requiring the use of cash in the nine months ended September 30, 2005 as compared to an increase in drafts payable of $6.2 million providing cash from financing activities for the nine months ended September 30, 2006. In order to reduce our interest costs, we do not borrow money to fund outstanding checks until they are presented to the bank. Fluctuations in drafts payable are caused by timing of disbursements, cash receipts and draws on our revolving credit facility.

Working Capital Deficit. We had a working capital deficit of $34.3 million as of September 30, 2006, primarily due to drafts payable of $36.0 million. As discussed under "Cash Flows" above, in order to reduce our interest costs we do not borrow money to fund outstanding checks until they are presented to our bank. We borrow money under our $1.0 billion credit facility to fund checks as they are presented. As of September 30, 2006, we had approximately $547.2 million of available borrowing capacity under this facility.

Issuance of Senior Subordinated Series C Units. On June 29, 2006, we issued an aggregate of 12,829,650 senior subordinated series C units representing limited partner interests in a private equity offering for net proceeds of $359.3 million. The senior subordinated series C units were issued at a purchase price of $28.06 per unit, which represents a discount of 25% to the market value of common units on such date. CEI purchased 6,414,830 of the senior subordinated series C units issued at that price. In addition, Crosstex Energy GP, L.P. made a general partner contribution of $9.0 million in connection with this issuance which represents a 2% general partner contribution on the market value of the issued units.

Capital Requirements. The natural gas gathering, transmission, treating and processing businesses are capital-intensive, requiring significant investment to maintain and upgrade existing operations. Our capital requirements have consisted primarily of, and we anticipate will continue to be:

- Maintenance capital expenditures, which are capital expenditures made to replace partially or fully depreciated assets in order to maintain existing operating capacity of our assets and to extend their useful lives, or other capital expenditures which do not increase our cash flows; and
- Growth capital expenditures such as those to acquire additional assets to grow our business, to expand and upgrade gathering systems, transmission capacity, processing plants or treating plants, and to construct or acquire new pipelines, processing plants or treating plants, and expenditures made in support of that growth.

Given our objective of growth through acquisitions, we anticipate that we will continue to invest significant amounts of capital to grow and acquire assets. We actively consider a variety of assets for potential acquisitions.

We believe that cash generated from operations will be sufficient to meet our present quarterly distribution level of $0.55 per quarter and to fund a portion of our anticipated capital expenditures through September 30, 2007. Total capital expenditures are budgeted to be approximately $56.3 million for the remainder of 2006. We expect to fund the remaining capital expenditures from the proceeds of borrowings under the revolving credit facility discussed below. Our ability to pay distributions to our unit holders and to fund planned capital expenditures and to make acquisitions will depend upon our future operating performance, which will be affected by prevailing economic conditions in our industry and financial, business and other factors, some of which are beyond our control.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of September 30, 2006.

Indebtedness

As of September 30, 2006 and December 31, 2005, long-term debt consisted of the following (in thousands):

	September 30, 2006	December 31, 2005
Bank credit facility, interest based on Prime and/or LIBOR plus an applicable margin, interest rates (per the facility) at September 30, 2006 and December 31, 2005 were 7.21% and 6.69%, respectively	$ 400,000	$ 322,000
Senior secured notes, weighted average interest rate at September 30, 2006 and December 31, 2005 were 6.76% and 6.64%, respectively	500,883	200,000
Note payable to Florida Gas Transmission Company	600	650
	901,483	522,650
Less current portion	(10,012)	(6,521)
Debt classified as long-term	$ 891,471	$ 516,129

On June 29, 2006, we amended our bank credit facility, increasing availability under the facility to $1 billion, with an option to increase the aggregate commitment to $1.3 billion pursuant to an accordion provision. The maturity date was extended from November 2010 to June 2011.

Under the amended credit agreement, borrowings bear interest at our option at the administrative agent's reference rate plus 0% to 0.25% or LIBOR plus 1.00% to 1.75%. The applicable margin varies quarterly based on our leverage ratio. The fees charged for letters of credit range from 1.00% to 1.75% per annum, plus a fronting fee of 0.125% per annum. We will incur quarterly commitment fees based on the unused amount of the credit facilities. The amendment to the credit facility also adjusted financial covenants requiring us to maintain:

- an initial ratio of total funded debt to consolidated earnings before interest, taxes, depreciation and amortization (each as defined in the credit agreement), measured quarterly on a rolling four-quarter basis, of 5.25 to 1.0, pro forma for any asset acquisitions. The maximum leverage ratio is reduced to 4.75 to 1 beginning July 1, 2007 and further reduces to 4.25 to 1 on January 1, 2008. The maximum leverage ratio increases to 5.25 to 1 during an acquisition adjustment period, as defined in the credit agreement; and
- a minimum interest coverage ratio (as defined in the credit agreement), measured quarterly on a rolling four quarter basis, equal to 3.0 to 1.0.

Additionally, the bank credit facility was amended to allow for borrowings under our senior secured note shelf agreement to increase from $260 million to $510 million.

In 2006, we amended the shelf agreement governing the senior secured notes to increase its availability from $200.0 million to $510.0 million. In March 2006, we issued $60.0 million aggregate principal amount of senior secured notes with an interest rate of 6.32% and a maturity of ten years. In July 2006, we issued $245.0 million aggregate principal amount of senior secured notes with an interest rate of 6.96% and a maturity of ten years. Proceeds were used to pay indebtedness under our bank credit facility.

We were in compliance with all debt covenants at September 30, 2006 and expect to be in compliance for the next twelve months.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of September 30, 2006, is as follows:

	Payments Due by Period						
	Total	2006	2007	2008	2009	2010	Thereafter
				(In millions)			
Long-term debt	$ 901.5	$ 2.4	$ 10.0	$ 9.4	$ 9.4	$ 20.3	$ 850.0
Capital lease obligations	—	—	—	—	—	—	—
Operating leases	98.0	4.4	17.5	17.2	16.8	16.0	26.1
Unconditional purchase obligations	1.3	1.3	—	—	—	—	—
Other long-term obligations	—	—	—	—	—	—	—
Total contractual obligations	$ 1,000.8	$ 8.1	$ 27.5	$ 26.6	$ 26.2	$ 36.3	$ 876.1

The above table does not include any physical or financial contract purchase commitments for natural gas.

The unconditional purchase obligations for 2006 primarily relate to the construction of a processing plant associated with the Parker County expansion.

Recent Accounting Pronouncements

In June 2006, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 48 ("FIN 48"), *"Accounting for Uncertainty in Income Taxes".* FIN 48 is an interpretation of FASB Statement No. 109, *"Accounting for Income Taxes"* and must be adopted no later than January 1, 2007. FIN 48 prescribes a comprehensive model for recognizing, measuring, presenting and disclosing in the financial statements uncertain tax positions taken or expected to be taken. We are a pass-thru entity and do not expect a major impact on financial statement presentation as a result of FIN 48.

On September 13, 2006 the Securities Exchange Commission (SEC) issued Staff Accounting Bulletin No. 108 (“SAB 108”), which establishes an approach that requires quantification of financial statement errors based on the effects of the error on each of the company’s financial statements and the related disclosures. SAB 108 requires the use of a balance sheet and an income statement approach to evaluate whether either of these approaches results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material.

Disclosure Regarding Forward-Looking Statements

This Quarterly Report on Form 10-Q includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended that are based on information currently available to management as well as management’s assumptions and beliefs. Statements included in this report which are not historical facts are forward-looking statements. These statements can be identified by the use of forward-looking terminology including “forecast,” “may,” “believe,” “will,” “expect,” “anticipate,” “estimate,” “continue” or other similar words. These statements discuss future expectations, contain projections of results of operations or of financial condition or state other “forward-looking” information. Such statements reflect our current views with respect to future events based on what we believe are reasonable assumptions; however, such statements are subject to certain risks and uncertainties. In addition to specific uncertainties discussed elsewhere in this Form 10-Q, the risk factors set forth in Part I, “Item 1A. Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2005, and those set forth in Part III, “Item 1A. Risk Factors” of this report may affect our performance and results of operations. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may differ materially from those in the forward-looking statements. We disclaim any intention or obligation to update or review any forward-looking statements or information, whether as a result of new information, future events or otherwise.

Item 3. ***Quantitative and Qualitative Disclosures about Market Risk***

Market risk is the risk of loss arising from adverse changes in market rates and prices. We face market risk from commodity price variations, primarily due to fluctuations in the price of a portion of the natural gas we sell, with respect to the portion of the natural gas we process and for which we have taken the processing risk, we are at risk for the difference in the value of the NGL products we produce versus the value of the gas used in fuel and shrinkage in their production. In addition, a portion of our fees at certain processing operations is denominated in NGLs. We also incur credit risks and risks related to interest rate variations.

Commodity Price Risk. Approximately 6.5% of the natural gas we market is purchased at a percentage of the relevant natural gas index price, as opposed to a fixed discount to that price. As a result of purchasing the gas at a percentage of the index price, our resale margins are higher during periods of higher natural gas prices and lower during periods of lower natural gas prices. As of September 30, 2006, we have hedged approximately 83% of our exposure to gas price fluctuations through December 2006, approximately 78% of our exposure to gas price fluctuations for the year ending December 2007, and approximately 15% of our exposure to gas price fluctuations for the first quarter of 2008. We also have hedges in place covering at least 100% of the minimum liquid volumes we expect to receive through the end of 2007 and approximately 20% for the first quarter of 2008 at our south Louisiana assets; and 80% of the liquids at our other assets in 2006, 81% in 2007, and 20% for the first quarter of 2008.

Another price risk we face is the risk of mismatching volumes of gas bought or sold on a monthly price versus volumes bought or sold on a daily price. We enter each month with a balanced book of gas bought and sold on the same basis. However, it is normal to experience fluctuations in the volumes of gas bought or sold under either basis, which leaves us with short or long positions that must be covered. We use financial swaps to mitigate the exposure at the time it is created to maintain a balanced position.

We have commodity price risk associated with our processed volumes of natural gas. We currently process gas under four main types of contractual arrangements:

1. *Keep-whole contracts:* Under this type of contract, we pay the producer for the full amount of inlet gas to the plant, and we make a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas volumes lost (“shrink”) in processing. Our margins from these contracts are high during periods of high liquids prices relative to natural gas prices, and can be negative during periods of high natural gas prices relative to liquids prices. We control our risk on our current keep-whole contracts primarily through our ability to bypass processing when it is not profitable for us.

2. *Percent of proceeds contracts:* Under these contracts, we receive a fee in the form of a percentage of the liquids recovered, and the producer bears all the cost of the natural gas shrink. Therefore, our margins from these contracts are greater during periods of high liquids prices. Our margins from processing cannot become negative under percent of proceeds contracts, but will decline during periods of low NGL prices.

3. *Theoretical processing contracts:* Under these contracts, we stipulate with the producer the assumptions under which we will assume processing economics for settlement purposes, independent of actual processing results or whether the stream was actually processed. These contracts tend to have an inverse result to the keep-whole contracts, with better margins as processing economics worsen.

4. *Fee based contracts:* Under these contracts we have no commodity price exposure, and are paid a fixed fee per unit of volume that is treated or conditioned.

Our primary commodity risk management objective is to reduce volatility in our cash flows. We maintain a Risk Management Committee, including members of senior management, which oversees all hedging activity. We enter into hedges for natural gas and NGLs using NYMEX futures or over-the-counter derivative financial instruments with only certain well-capitalized counterparties which have been approved by our Risk Management Committee.

The use of financial instruments may expose us to the risk of financial loss in certain circumstances, including instances when (1) sales volumes are less than expected requiring market purchases to meet commitments or (2) our counterparties fail to purchase the contracted quantities of natural gas or otherwise fail to perform. To the extent that we engage in hedging activities we may be prevented from realizing the benefits of favorable price changes in the physical market. However, we are similarly insulated against unfavorable changes in such prices.

We manage our price risk related to future physical purchase or sale commitments for our producer services activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance our future commitments and significantly reduce our risk to the movement in natural gas prices. However, we are subject to counterparty risk for both the physical and financial contracts. We account for certain of our producer services natural gas marketing activities as energy trading contracts or derivatives. These energy trading contracts are recorded at fair value with changes in fair value reported in earnings. Accordingly, any gain or loss associated with changes in the fair value of derivatives and physical delivery contracts relating to our producer services natural gas marketing activities are recognized in earnings as profit or loss on energy trading contracts immediately.

For each reporting period, we record the fair value of open energy trading contracts based on the difference between the quoted market price and the contract price. Accordingly, the change in fair value from the previous period is reported as (gain) loss on derivatives in the statement of operations. In addition, realized gains and losses from settled contracts are also recorded in profit or loss on energy trading contracts. As of September 30, 2006, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements, natural gas liquids puts and other derivative instruments had a net fair asset value of $12.8 million, excluding the fair value asset of $2.5 million associated with the NGL puts. The aggregate effect of a hypothetical 10% increase in gas and NGL prices would result in a decrease of approximately $6.7 million to a net asset of these contracts as of September 30, 2006 of $6.1 million. The value of the NGL puts would also decrease as a result of an increase in NGL prices, but we are unable to determine the impact of a 10% price change. Our maximum loss on these puts is the remaining $2.5 million fair value of the puts.

Concentration Risk. The counterparties to substantially all of our derivative contracts as of September 30, 2006 were BP Corporation, Total Gas & Power and J. Aron & Co., a subsidiary of Goldman Sachs. Although we do not believe we have a counterparty risk with any party, our loss would be substantial if any of these parties were to default.

Interest Rate Risk. We are exposed to changes in interest rates, primarily as a result of our long-term debt with floating interest rates. At September 30, 2006, we had $400.0 million of indebtedness outstanding under floating rate debt. The impact of a 1% increase in interest rates on our expected debt would result in an increase in interest expense and a decrease in income before taxes of approximately $4.0 million per year. This amount has been determined by considering the impact of such hypothetical interest rate increase on our non-hedged, floating rate debt outstanding at September 30, 2006.

Operational Risk. As with all mid-stream energy companies and other industrials, we have operational risk associated with operating our plant and pipeline assets that can have a financial impact, either favorable or unfavorable, and as such risk must be effectively managed. We view our operational risk in the following categories.

- *General Mechanical Risk.* Both our plants and pipelines expose us to the possibilities of a mechanical failure or process upset that can result in loss of revenues and replacement cost of either volume losses or damaged equipment. These mechanical failures manifest themselves in the form of equipment failure/malfunction as well as operator error. We are proactive in managing this risk on two fronts. First we effectively hire and train our operational staff to operate the equipment in a safe manner, consistent with defined processes and procedures, and second, we perform preventative and routine maintenance on all of our mechanical assets.
- *Measurement Risk.* In complex midstream systems such as ours, it is normal for there to be differences between gas measured into our systems and those measured out of the system which is referred to as system balance. These system balances are normally due to changes in line pack, gas vented for routine operational and non-routine reasons, as well as due to the inherent inaccuracies in the physical measurement of gas. We employ the latest gas measurement technology when appropriate, in the form of EFM (Electronic Flow Measurement) computers. Nearly all of our new supply and market connections are equipped with EFM. Retro-fitting older measurement technology is done on a case-by-case basis. Electronic digital data from these devices can be transmitted to a central control room via radio, telephone, cell phone, satellite or other means. With EFM computers, such a communication system is capable of monitoring gas flows and pressures in real-time and is commonly referred to as SCADA (Supervisory Control And Data Acquisition). We expect to continue to increase our reliance on electronic flow measurement and SCADA, which will further increase our awareness of measurement discrepancies as well as reduce our response time should a pipeline failure occur.

Item 4. ***Controls and Procedures***

(a) Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of Crosstex Energy GP, LLC, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of September 30, 2006 in alerting them in a timely manner to material information required to be disclosed in our reports filed with the Securities and Exchange Commission.

(b) Changes in Internal Control Over Financial Reporting

Since the first quarter of 2006, we have implemented accounting system improvements to settle gas purchases through our accounting systems and to reconcile prepayments to suppliers on our general ledger and conducted additional training of new personnel. In addition, we have added new procedures for the analysis of account reconciliations and a more detailed analytical review of gross margin cycle accounts. These accounting process improvements were made to remediate the previously disclosed material weakness related to our gas settlement and reconciliation processes.

Except as set forth above, there have been no other changes in our internal controls over financial reporting that occurred in the three months ended September 30, 2006 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II — OTHER INFORMATION

Item 1A. *Risk Factors*

Other than the risk factor presented below, there have been no material changes from the risk factors disclosed under the heading "Risk Factors" in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2005 (the "Annual Report"). The risk factor below updates, and should be read in conjunction with, the risk factors disclosed in our Annual Report and in our other filings with the SEC.

If our assumptions used in making the acquisition of the Barnett Shale systems and facilities from Chief Holdings LLC are inaccurate, our future financial performance may be limited.

We acquired certain natural gas gathering pipeline systems and related facilities in the Barnett Shale, which we refer to as the Midstream Assets, from Chief Holdings LLC in June 2006. This acquisition was made based our understanding of future drilling plans by Devon Energy Corporation, which acquired Chief's producing assets and acreage previously owned by Chief that is dedicated to the Midstream Assets. In addition, we assumed in our analysis the continued drilling success by other producers that own acreage dedicated to the Midstream Assets, production success on acreage not dedicated on the system and that we will be able to tie a certain portion of that new production into the system. Production currently flowing through the system is very small relative to the quantities we have assumed will be developed in the next few years. If our assumptions are inaccurate, the drilling plans of the producers are delayed, the producers are not successful in completing their wells or we are not successful in our commercial efforts to tie in gas from undedicated acreage, then the anticipated results from the acquisition of the Midstream Assets could be significantly negatively impacted. In addition, the failure to successfully integrate the Midstream Assets with our existing business and operations in a timely manner may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Item 6. *Exhibits*

The exhibits filed as part of this report are as follows (exhibits incorporated by reference are set forth with the name of the registrant, the type of report and registration number or last date of the period for which it was filed, and the exhibit number in such filing):

Number		Description
3.1	—	Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1, file No. 333-97779).
3.2	—	Fifth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of June 29, 2006 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006).
3.3	—	Certificate of Limited Partnership of Crosstex Energy Services, L.P. (incorporated by reference to Exhibit 3.3 to our Registration Statement on Form S-1, file No. 333-97779).
3.4	—	Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy Services, L.P., dated as of April 1, 2004 (incorporated by reference to Exhibit 3.5 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
3.5	—	Certificate of Limited Partnership of Crosstex Energy GP, L.P. (incorporated by reference to Exhibit 3.5 to our Registration Statement on Form S-1, file No. 333-97779)

Number		Description
3.6	—	Agreement of Limited Partnership of Crosstex Energy GP, L.P., dated as of July 12, 2002 (incorporated by reference to Exhibit 3.6 to our Registration Statement on Form S-1, file No. 333-97779).
3.7	—	Certificate of Formation of Crosstex Energy GP, LLC (incorporated by reference to Exhibit 3.7 to our Registration Statement on Form S-1, file No. 333-97779).
3.8	—	Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of December 17, 2002 (incorporated by reference to Exhibit 3.8 to our Registration Statement on Form S-1, file No. 333-97779).
10.1	—	Amended and Restated Note Purchase Agreement, dated as of July 25, 2006, among Crosstex Energy, L.P. and the Purchasers listed on the Purchaser Schedule attached thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated July 25, 2006, filed with the Commission on July 28, 2006).
31.1*	—	Certification of the principal executive officer.
31.2*	—	Certification of the principal financial officer.
32.1*	—	Certification of the principal executive officer and principal financial officer of the Partnership pursuant to 18 U.S.C. Section 1350.

* Filed herewith.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 8th day of November, 2006.

CROSSTEX ENERGY, L.P.

By: Crosstex Energy GP, L.P.,
its general partner

By: Crosstex Energy GP, LLC,
its general partner

By: /s/ William W. Davis
William W. Davis
Executive Vice President and
Chief Financial Officer

EXHIBIT INDEX

Number		Description
3.1	—	Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1, file No. 333-97779).
3.2	—	Fifth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of June 29, 2006 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006).
3.3	—	Certificate of Limited Partnership of Crosstex Energy Services, L.P. (incorporated by reference to Exhibit 3.3 to our Registration Statement on Form S-1, file No. 333-97779).
3.4	—	Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy Services, L.P., dated as of April 1, 2004 (incorporated by reference to Exhibit 3.5 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
3.5	—	Certificate of Limited Partnership of Crosstex Energy GP, L.P. (incorporated by reference to Exhibit 3.5 to our Registration Statement on Form S-1, file No. 333-97779).
3.6	—	Agreement of Limited Partnership of Crosstex Energy GP, L.P., dated as of July 12, 2002 (incorporated by reference to Exhibit 3.6 to our Registration Statement on Form S-1, file No. 333-97779).
3.7	—	Certificate of Formation of Crosstex Energy GP, LLC (incorporated by reference to Exhibit 3.7 to our Registration Statement on Form S-1, file No. 333-97779).
3.8	—	Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of December 17, 2002 (incorporated by reference to Exhibit 3.8 to our Registration Statement on Form S-1, file No. 333-97779).
10.1	—	Amended and Restated Note Purchase Agreement, dated as of July 25, 2006, among Crosstex Energy, L.P. and the Purchasers listed on the Purchaser Schedule attached thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated July 25, 2006, filed with the Commission on July 28, 2006).
31.1*	—	Certification of the principal executive officer.
31.2*	—	Certification of the principal financial officer.
32.1*	—	Certification of the principal executive officer and principal financial officer of the Partnership pursuant to 18 U.S.C. Section 1350.

* Filed herewith.

Exhibit 31.1

CERTIFICATIONS

I, Barry E. Davis, President and Chief Executive Officer of Crosstex Energy GP, LLC, the general partner of Crosstex Energy GP, L.P., the general partner of the registrant, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Crosstex Energy, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused the disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial data information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

/s/ Barry E. Davis

Barry E. Davis,
President and Chief Executive Officer
(principal executive officer)

Date: November 8, 2006

Exhibit 31.2

CERTIFICATIONS

I, William W. Davis, Executive Vice President and Chief Financial Officer of Crosstex Energy GP, LLC, the general partner of Crosstex Energy GP, L.P., the general partner of the registrant, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Crosstex Energy, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused the disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial data information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

/s/ William W. Davis

William W. Davis,
Executive Vice President and Chief Financial Officer
(principal financial and accounting officer)

Date: November 8, 2006

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Crosstex Energy, L.P. (the “Registrant”) on Form 10-Q for the quarter ended September 30, 2006 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), each of the undersigned, Barry E. Davis, Chief Executive Officer of Crosstex Energy GP, LLC, and William W. Davis, Chief Financial Officer of Crosstex Energy GP, LLC, certifies, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Registrant.

/s/ Barry E. Davis
Barry E. Davis
Chief Executive Officer

November 8, 2006

/s/ William W. Davis
William W. Davis
Chief Financial Officer

November 8, 2006

A signed original of this written statement required by Section 906 has been provided to the Registrant and will be retained by the Registrant and furnished to the Securities and Exchange Commission or its staff upon request. The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Report.